

burning combinations of fossil fuels are rounded to the nearest 500 ppm.

(5) For affected facilities burning fossil fuel, alone or in combination with non-fossil fuel, the span value of the sulfur dioxide continuous monitoring system at the inlet to the sulfur dioxide control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the sulfur dioxide control device is 50 percent of maximum estimated hourly potential emissions of the fuel fired.

(j) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For Method 6, Method 6A or 6B (whenever Methods 6 and 3 or 3B data are used) or 6C may be used. Each Method 6B sample obtained over 24 hours represents 24 1-hour averages. If Method 6A or 6B is used under paragraph (i) of this section, the conditions under §60.46(d)(1) apply; these conditions do not apply under paragraph (h) of this section.

(2) For Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time for each run shall be 1 hour.

(3) For Method 3, Method 3A or 3B may be used if the sampling time is 1 hour.

(4) For Method 3B, Method 3A may be used.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989; 55 FR 5212, Feb. 14, 1990; 55 FR 18876, May 7, 1990]

#### **§ 60.48a Compliance determination procedures and methods.**

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the methods in appendix A of this part or the methods and procedures as specified in this section, except as provided in §60.8(b). Section 60.8(f) does not apply to this section for SO<sub>2</sub> and NO<sub>x</sub>. Acceptable alternative methods are given in paragraph (e) of this section.

(b) The owner or operator shall determine compliance with the particulate matter standards in §60.42a as follows:

(1) The dry basis F factor (O<sub>2</sub>) procedures in Method 19 shall be used to

compute the emission rate of particulate matter.

(2) For the particulate matter concentration, Method 5 shall be used at affected facilities without wet FGD systems and Method 5B shall be used after wet FGD systems.

(i) The sampling time and sample volume for each run shall be at least 120 minutes and 1.70 dscm (60 dscf). The probe and filter holder heating system in the sampling train may be set to provide an average gas temperature of no greater than 160±14 °C (320±25° F).

(ii) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B shall be used to determine the O<sub>2</sub> concentration. The O<sub>2</sub> sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the O<sub>2</sub> traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O<sub>2</sub> traverse points. If the grab sampling procedure is used, the O<sub>2</sub> concentration for the run shall be the arithmetic mean of all the individual O<sub>2</sub> concentrations at each traverse point.

(3) Method 9 and the procedures in §60.11 shall be used to determine opacity.

(c) The owner or operator shall determine compliance with the SO<sub>2</sub> standards in §60.43a as follows:

(1) The percent of potential SO<sub>2</sub> emissions (%P<sub>s</sub>) to the atmosphere shall be computed using the following equation:

$$\%P_s = [(100 - \%R_t) (100 - \%R_g)] / 100$$

where:

%P<sub>s</sub>=percent of potential SO<sub>2</sub> emissions, percent.

%R<sub>t</sub>=percent reduction from fuel pretreatment, percent.

%R<sub>g</sub>=percent reduction by SO<sub>2</sub> control system, percent.

(2) The procedures in Method 19 may be used to determine percent reduction (%R<sub>t</sub>) of sulfur by such processes as fuel pretreatment (physical coal cleaning, hydrodesulfurization of fuel oil, etc.), coal pulverizers, and bottom and flyash interactions. This determination is optional.

(3) The procedures in Method 19 shall be used to determine the percent SO<sub>2</sub>

reduction (%R<sub>g</sub> of any SO<sub>2</sub> control system. Alternatively, a combination of an “as fired” fuel monitor and emission rates measured after the control system, following the procedures in Method 19, may be used if the percent reduction is calculated using the average emission rate from the SO<sub>2</sub> control device and the average SO<sub>2</sub> input rate from the “as fired” fuel analysis for 30 successive boiler operating days.

(4) The appropriate procedures in Method 19 shall be used to determine the emission rate.

(5) The continuous monitoring system in § 60.47a (b) and (d) shall be used to determine the concentrations of SO<sub>2</sub> and CO<sub>2</sub> or O<sub>2</sub>.

(d) The owner or operator shall determine compliance with the NO<sub>x</sub> standard in § 60.44a as follows:

(1) The appropriate procedures in Method 19 shall be used to determine the emission rate of NO<sub>x</sub>.

(2) The continuous monitoring system in § 60.47a (c) and (d) shall be used to determine the concentrations of NO<sub>x</sub> and CO<sub>2</sub> or O<sub>2</sub>.

(e) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For Method 5 or 5B, Method 17 may be used at facilities with or without wet FGD systems if the stack temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of §§ 2.1 and 2.3 of Method 5B may be used in Method 17 only if it is used after wet FGD systems. Method 17 shall not be used after wet FGD systems if the effluent is saturated or laden with water droplets.

(2) The F<sub>c</sub> factor (CO<sub>2</sub>) procedures in Method 19 may be used to compute the emission rate of particulate matter under the stipulations of § 60.46(d)(1). The CO<sub>2</sub> shall be determined in the same manner as the O<sub>2</sub> concentration.

(f) Electric utility combined cycle gas turbines are performance tested for particulate matter, sulfur dioxide, and nitrogen oxides using the procedures of Method 19 (appendix A). The sulfur dioxide and nitrogen oxides emission rates from the gas turbine used in Method 19 (appendix A) calculations are determined when the gas turbine is

performance tested under subpart GG. The potential uncontrolled particulate matter emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/million Btu) heat input.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989; 55 FR 5212, Feb. 14, 1990]

#### § 60.49a Reporting requirements.

(a) For sulfur dioxide, nitrogen oxides, and particulate matter emissions, the performance test data from the initial performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

(b) For sulfur dioxide and nitrogen oxides the following information is reported to the Administrator for each 24-hour period.

(1) Calendar date.

(2) The average sulfur dioxide and nitrogen oxide emission rates (ng/J or lb/million Btu) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

(3) Percent reduction of the potential combustion concentration of sulfur dioxide for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

(4) Identification of the boiler operating days for which pollutant or diluent data have not been obtained by an approved method for at least 18 hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction (NO<sub>x</sub> only), emergency conditions (SO<sub>2</sub> only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, malfunction, or emergency conditions.

(6) Identification of “F” factor used for calculations, method of determination, and type of fuel combusted.